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Shell Exploration & Production Company

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March 8, 2002

Department of the Interior
Minerals Management Service; MS 4024
Attn: Rules Processing Team (RPT)
381 Elden Street
Herndon, Virginia 20170-4817

Gentlemen:

Re: Notice of Proposed Rulemaking
Procedures for Dealing with Sustained Casing Pressure
(FR 56620, 11/9/2001)

Shell Exploration and Production Company would like to take this opportunity to endorse the comments previously submitted by The Offshore Operators Committee (OOC) on the above subject. Additionally, we would like to address in our comments below some of the topics mentioned in the OOC comments that we believe are particularly significant.

The points that Shell believes are particularly relevant include the following:

- In the Preamble to the OOC's comments, OOC refers to MMS data collections that show that SCP is most often caused by leaks in the production tubing and tubing connectors. That is not our operational experience. Further, we are also unaware of any study that comes to the aforementioned conclusion. We do believe, however, that in situations where a tubing leak occurs that renders the SCSSV ineffective, a safety issue exists and the tubing should be repaired. In those cases where the SCSSV acts a barrier then we believe that monitoring the tubing/production annulus should be sufficient until the next time a workover rig is on the platform. For wells completed with subsea wellheads, we also concur with the OOC proposal that monitoring the tubing/production annulus should be sufficient.

- We are strongly opposed to the MMS's position that subsea trees installed after January 1, 2005 must have a method for monitoring all casing annuli for SCP. This requirement would have a tremendous impact on Shell as well as on Industry. In our opinion nothing has changed from a technology development, historical evidence, or risk assessment standpoint that indicates that MMS's current policy of waiving the requirement to provide a method for monitoring all casing annuli for SCP on subsea wells should be modified. <u>Most importantly</u>, Shell believes that the reliability of the subsea wellhead, subsea tree, umbilical and control systems will actually decrease due to the additional leak paths that will have to be introduced to accommodate monitoring additional annuli over and above the tubing/production annulus that is currently being monitored in wells completed with a subsea wellhead.

- The following points come from the OOC's General Comments Section on Regulatory Planning and Review--Our estimation of the cost impact of the MMS's proposed changes that would allow monitoring of all annuli in subsea wells is significantly above the MMS estimate of $175,000 per well. We do not think that the full impact of this proposal has been considered and additional costs should be added. We believe that redesigning the subsea wellhead, subsea tree, umbilical, control systems and host platform systems would range from $3 MM to $6.5 MM per subsea well for modification of the aforementioned items/systems. The above "redesign" costs still do not capture the additional operational costs that will have to be incurred for items such as increased methanol usage, additional interventions, and/or deferred production associated with interventions on these wells. Further, MMS has also not included any costs to eliminate SCP in wells completed with a subsea wellhead. In the event that MMS required remediation of SCP in a subsea well, the operator would have to move on a MODU, cut and retrieve and/or perforate the production casing to attempt to bleed and isolate the casing annulus. The estimated cost for this operation is $12 to 18 MM per well. Finally, the costs associated with lost production due to premature abandonment resulting from remediation work has not even been estimated. Lost reserves could ultimately be the most significant dollar loss to both the MMS and Industry in revenues/royalties.

- The following points come from the OOC's General Comments Section dealing with Fixed Platform Wells—We don't understand the reasons for MMS wanting to treat producing and non-producing wells differently. We do not understand how MMS can infer some additional risk to a non-producing well over a producing well, just by virtue of its "non-producing status". This regulation would result in the acceleration of the plugging and abandoning of non-producing wells. However, we don't recommend this approach since these non-producing wells are the avenue through which wells may be side tracked and (not yet discovered) reserves ultimately developed. This situation would again result in lost revenues and royalties similar to that discussed in the final sentence of the preceding bullet.

- The following points come from the OOC's General Comments Section dealing with Subsea Wells--As you will see from our quote of a section of the OOC's comments we agree with their assessment that MMS truly does not fully understand the differences between fixed platform systems and subsea systems. The following is a partial quote from the OOC comments and each point is worth mentioning again:

    - The manufacture and physical position of the casing hanger to the wellhead is totally different for wells utilizing a surface wellhead versus a subsea wellhead. The configuration difference creates various technical and operational challenges that are not simply resolved with the proposed regulatory changes.

    - Current technology of subsea wellhead systems does not provide the ability to monitor all casing annuli. The creation of the external vent port between each of the casing hanger annuli or an internal casing hanger seal monitoring capability would be required to be developed and implemented.

    - Any monitoring ports, beyond the added risk of an environmental leak during drilling, completions or production operations would be susceptible to failure needing repair. Repeated operations to meet the frequent testing for sustained or unsustained casing pressure could lead to failure requiring a workover or for the well to be plugged and abandoned. Added workovers due to the introduction of the increased well complexity would result in added costs, and more importantly, added risk to well control problems, environmental risk and personnel exposure. Even leaving a monitoring valve open for long periods would add the risk of not being sure it would test or close when needed.

- To add a penetration through the subsea wellhead system would require a major revision to API Specification 17D which specifically prohibits the penetrations into a subsea high pressure wellhead housing. The concept of providing multiple penetrations through the wellhead housing to provide access to all the casing annuli will require a dual barrier concept of sealing for the inboard primary seal surface on the external side of the wellhead. Also, redundant, removable and repairable ROV remote controlled gate valves of full rated pressure will be needed. To enable this annular access valve arrangement creates a new challenge to enable BOP guidance systems and completion guide base frames to be deployed and removed as required.

- Another option to provide monitoring and venting of the casing annuli through each casing hanger into the subsea tree would require significant redesign of the wellhead and subsea tree systems. The technical design, operational review and full scale testing of the system would be required to ensure that production casing pressure could not enter the outer drilling casing annuli. Starting with the current design of casing hangers and subsea trees, it would be very difficult to maintain the dual pressure barrier design. This would be necessary to eliminate the potential and very high risk prospect of production wellbore fluids from entering the outer casing annuli which could lead to a casing failure and potentially an uncontrolled well flow situation.

- The types of fluids that are removed from the tubing/production casing annulus and the outer drilling casing annuli are significantly different from each other. The fluid in the tubing/production annulus is typically a clean, filtered, low-to-no solids fluid (clear brine packer fluid). The fluid in the outer casing annuli is typically high solid drilling mud that was in use at the time of casing cementing as a trapped fluid below the casing hanger and seal assembly. Traditionally on surface wellheads, the bleeding of the primary production casing annulus is done via a tubing head valve just below the tubing hanger. On a subsea well, a similar capability exists. The clean fluid can be flowed through a dedicated annulus bleed line or via the production flow line. If the outer annulus is bled off through a bleed line, the high solid drilling fluid will quickly, if not immediately, plug the bleed line in the umbilical and thus render the monitoring system useless. Additionally, hydrates are likely to form in the control line if leaks in the system occur which will also render the monitoring system useless.

- The methodology of running diagnostic tests should be carefully considered and not just be an extension of the protocols used for fixed platform wells. The risk of plugging the annulus bleed line should be considered in the test design. The time to bleed off the casing pressure through a control umbilical would be very long due to small diameter of the bleed line. The distance between the subsea well and the host platform must be taken into consideration. The protocols for fixed platform wells call for the casing pressure to be bled to zero (surface pressure). For a subsea well, the casing pressure will be affected by the hydrostatic pressure of the fluid medium filling the bleed line and this pressure would have to be accounted for. The protocol would also need to ensure that the hose jumpers would not collapse by limiting the vented pressure for a casing annulus above the ambient subsea pressure to minimize the collapse pressure of the hose jumpers.

Finally, the complexity of the casing pressure monitoring, reporting and documentation process (including our internal office and offshore training processes) has created a tremendous administrative burden for us and, I think, all operators. It is safe to say that we devote more man-hours to the aforementioned activities associated with casing pressure administration than almost any other administrative process that MMS requires.

Hopefully, based on the comments from OOC and these comments, you will adopt the OOC's recommendation to withdraw this rulemaking or at least hold it in abeyance until the work proposed by the OOC and API can be completed.

Should you or members of your staff have any questions regarding this matter, please contact either Ms. Jo Ann Sutton at (504) 728-7757 or me at (504) 728-6982.

Yours truly,

Peter Velez

Peter K. Velez
Manager, Regulatory Affairs